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BEFORE THE ARIZONA CORPORATION

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2006 OCT 25 P 4: 45

OCT 25 2006

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In the Matter of the General Investigation of Distributed Generation and Interconnections for Potential Retail Electric Competition Rules Consideration

Docket No. E-00000A-99-0431

ARIZONA PUBLIC SERVICE COMPANY'S COMMENTS TO STAFF'S REQUEST FOR WRITTEN COMMENTS IN THE NET METERING WORKSHOP

Arizona Public Service Company ("APS" or the "Company") hereby submits its comments to the Arizona Corporation Commission (the "Commission") to Staff's Request for Written Comments in the Net Metering Workshop.

1. How would net metering support the three purposes of PURPA?

The three purposes are:

a) Conservation of energy supplied by electric utilities;

b) Optimal efficiency of electric utility facilities and resources;

c) Equitable rates for electric consumers.

APS Response:

Net metering as a stand alone concept does not specifically support any of the above three mentioned stated purposes. However, the Company will respond to this question on the premise that a well-designed net metering program for renewable resources supports distributed generation which can support portions of these stated purposes.

a) The use of distributed generation does provide an offset to energy otherwise produced by the utility. However, there is no guarantee that this results in an overall reduction in energy used by the customer (conservation of energy).

b) Distributed generation has the potential to provide benefits to the distribution grid which include voltage support, reliability, lower losses, power quality improvements, and potential deferral or reduction in distribution investment. Each of these potential benefits can have a direct impact on the efficiency of electric utility facilities and resources. However, these benefits are specific to each distributed generation installation and the utility is unable at this time to quantify the cost-benefit of adding distributed generation to the APS distribution system. Please refer to APS' response to question 7 below for a more detailed explanation regarding APS' inability to quantify the costs and benefits of net metering.

APS has joined with ASU and Valley homebuilders to develop a study to look at the impact on our distribution system from concentrated development of rooftop systems through the Solar America Initiative.

c) Net metering, in general, does not meet PURPA's stated purpose of providing equitable rates for electric consumers. Customers taking service under net metering rates do not pay appropriate transmission and distribution costs, nor do they pay the full amount (and possibly none) of non-avoidable charges such as Competition Rules Compliance Charge, EPS Surcharge, DSM Cost Adjustment, Power Supply Adjustment (for deferred fuel costs incurred during prior periods) and a Transmission Cost Adjustment as provided under APS' rate schedules. For these reasons, net metering rates do not yield sufficient revenue to cover cost. Therefore, these costs would have to be borne by customers who do not have distributed generation (net metering Distributed Generation customers are being subsidized by non-Distributed Generation customers).

2. Participation in and Eligibility for Net Metering.

a) Should there be a cap on total participation?

<u>APS Response:</u>

Yes, the Company believes that APS' total participation in an initial net metering program should be capped at 15 MW of renewable resources, which is consistent with total participation caps in other jurisdictions. Specifically, 23 of the 41 states that offer net metering have caps on the aggregate level of participation (as reported by the Interstate Renewable Energy Council). 18 of the 23 states that limit aggregate program participation have caps that are at or below 0.2% of the utility's peak load. The Company's proposed cap of 15 MW on aggregate participation is roughly equal to 0.2% of APS' "own-load" system peak. The Company also offers net billing, without a cap, that the Company believes is a more appropriate mechanism for larger DG installations.

b) Should there be a cap on project size?

APS Response:

Yes, APS believes that a 10 kW cap on the individual generator size is appropriate for net metering. Most other state jurisdictions that offer net metering have relatively small caps on the individual size of participating generators and a 10 kW cap on individual generator size is consistent with these other jurisdictions. Specifically, 33 out of the 41 states that offer net metering have caps on generator size at or below 100 kW (as reported by the Interstate Renewable Energy Council).

Additionally, when a distributed generator incurs an outage the customer's associated load is typically not reduced; the utility's load would actually increase creating an additional instantaneous burden on power generation. In other words, the Company would have to backup the customer's generator with generation, transmission, and distribution capacity, while the Company would not have to back up an energy conservation measure. Under the Company's proposed net metering program, the customer is not charged for this backup service, which is one of the reasons that we believe that it should be offered to smaller renewable distributed generators with a maximum nameplate rating of 10 kW. APS already offers net billing (Rate Schedules EPR-2 and EPR-4) and partial requirements (Rate Schedules E-32R, E-52, and E-55) rates for larger customers which are designed to recover APS' fixed capital investment while still providing most of the benefits of net metering.

A properly designed net metering program provides an additional financial incentive to customers electing to install distributed generation and should only be offered to customers who need this additional incentive. Since net metering allows participating customers to avoid paying for fixed costs associated with providing electric service, it is important to limit, to the extent possible, any subsidization between distributed generation and non-distributed generation customers. Based on APS' experience, larger distributed generation units typically have more economies of scale, are cheaper to install on a dollar per kW basis, and the customer's decision to install distributed generation is not necessarily contingent on whether or not a net metering rate is offered. Furthermore, large customers that install moderate levels of renewable resource DG can realize the same benefits as net metering through net billing.

c) Which customer sectors should be allowed to participate?

<u>APS Response:</u>

The Company believes that an initial net metering rate should be made available to residential customers and general service customers with monthly demands less than or equal to 20 kW. This allows the net metering program to be used as a mechanism to attract small customers to install renewable generation by providing an additional incentive beyond the credit purchase under the Company's Solar Partners Incentive Program.

d) What type(s) of generation resources should be allowed to participate?

APS Response:

The net metering program should be applicable to renewable resource generation facilities, as defined in A.A.C. R14-2-1618 or successor, where the customer's generator(s) and load are permanently located on the same premise. Customers who install Distributed Generation from Non-renewable resources should not be eligible for net metering.

3. What types of meters should be used for net metering?

a) Dual meters?
b) Bidirectional meters?
c) Other metering technology?

APS Response:

While net metering rate schedules can technically be implemented with two standard meters, the Company believes that a single bi-directional meter is a better and lower-cost option. While the cost of two standard meters is slightly below the cost of a single bi-directional meter, employing two meters requires usage of a socket adapter or the installation of two sockets which eliminates any meter cost savings advantage. This is illustrated further in the customer options specified below:

	Electronic Meter	Bi-directional Meter
Meter Cost	$102.77	$335.51
No. Meters	2	1
Total Meter Cost	$205.54	$335.51
Socket Adapter[1]	$200.00	$0
Total Cost	$405.54	$335.51

[1] Socket adapters range in cost from approximately $200-250.

Furthermore, the Company prefers the operational requirements of the bi-directional meter for this application, which includes meter inventory, meter sets and meter reading. In fact, the Company is already using a single bi-directional meter for the current distributed generation rates, EPR-2 and EPR-4, so the Company's metering proposal under net metering would be consistent with its existing operations and meter changes would not be required. Existing uni-directional meters (electro-mechanical or electronic) would need to be changed out to a bi-directional meter for new customers electing to either sell power back to the utility under a net-billing rate schedule or to participate in a net metering program. The vast majority of other jurisdictions which offer net metering also use or require the use of a single bi-directional meter to implement the rate. The Company has not been able to identify any jurisdictions that use two meters to implement net metering.

4. How should net excess generation be treated?

a) Payment at utility's avoided cost?
b) Credit against future bills?
c) Credits roll forward indefinitely?
d) Credits roll forward for a fixed time period?
e) True up at predetermined rates?
f) Credits terminate without additional compensation?

<u>APS Response</u>:

Provided the Company proposed caps are in place, renewable resource energy generated by the customer in excess of their monthly consumption should be accumulated on a kWh basis and carried from month to month with any excess supply reset to zero at the end of each calendar year. This provides the customer with flexibility in sizing their DG units while not encouraging the over-sizing of distributed generation units.

5. Who should pay the costs of net metering?

a) The utility?
b) The net metering customer?
c) All ratepayers?

APS Response:

The Company believes if net metering customers do not pay the costs, such costs will have to be recovered from all ratepayers. APS proposes that the incremental cost for net metering, including the cost of meter changes, should be paid using revenues collected through the current EPS surcharge which is funded by APS' ratepayers. In addition, infrastructure costs, such as changes to the customer billing systems, should be funded through the EPS surcharge. Fixed costs associated with transmission and distribution, as well as non-avoidable costs, such as those mentioned in APS' response to question 1.c, that are not recovered from net metering customers should also be funded through the EPS surcharge.

6. Should rate structures be changed to accommodate net metering? If so, how?

APS Response:

APS does not believe rate structure changes are needed to accommodate net metering if the 10 kW and less generator size limit, the 15 MW of renewable resources program participation limit, and the proposal to collect un-recovered fixed costs are all approved. If modifications are made to the above mentioned guidelines, additional rate structure changes may be needed. APS does not object to changing rate schedules to accommodate net metering if:

a) any proposed rate structure changes strives to minimize subsidization between customers;
b) any proposed rate structure changes provide the Utility with the opportunity to recover costs and earn a fair rate of return on investment;

Potential rate structure modifications to consider include:

a) further utilization of net billing for larger customers instead of net metering;

b) Appropriately designing rates to collect all customer-related costs through the basic service charge, all fixed or non by-passable costs through a fixed charge or a demand charge, and all energy-related costs through the energy or per kWh charge.

7. What are the costs and benefits of net metering?

APS Response:

If a customer installs and operates a renewable resources distributed generator and uses it offset the amount of utility provided energy, APS will see a reduction in fuel and/or purchased power costs. At this time, APS cannot fully quantify the cost-benefit of adding the renewable resource Generating Facility. However, APS has joined with ASU and Valley homebuilders to develop a study which looks at the impact on our distribution system from concentrated development of rooftop systems. This study should be completed in three years.

Pending the results of the aforementioned study, APS is unable to quantify the cost-benefit of adding DG to the distributionsystem for the following reasons:

A. Unable to quantify the benefits of non-firm non-dispatchable power. APS cannot recognize renewable resource distributed generator upgrades as firm, reliable power because the owner of the facility, not APS, will control the operation of the Generating Facility. Because the addition of the renewable resource Generating Facility cannot be considered firm power, APS cannot rely upon the addition of distributed generation to reduce the size of its feeder conductors, substation transformers or other distribution equipment. The Utility must still plan its system to serve load under conditions when the generator would be unavailable. Additionally, the Utility cannot rely on the renewable resource Generating Facility for voltage support. Thus, upgrades associated with non-firm power cannot assist the Utility in deferring any additional needs for power because the Utility cannot rely upon such addition as a firm resource.

B. Unable to Quantify the Benefits to Reliability. APS is unable to accurately assess a renewable resource Generating Facility's benefit to the reliability of the distribution system because APS has no control over the operation of the renewable resource Generating Facility in order to ensure that APS' reliability requirements are satisfied. Nor does APS have any way of measuring how reliable the renewable resource Generating Facility will be as a generating source. The owner has no obligation to run such resource to support APS' reliability or peak load needs. Thus, the distributed generator is the only entity that may reasonably benefit from the resource.

C. No Guarantee Utilities Will Realize the Long-term Benefits of Adding Such Upgrades. The Utility has no way of assessing how long the Customer may remain in business. Thus, this provision would seemingly require the Utility to compensate the distributed generator the cost of its system upgrades without obligating the distributed generator to stay in business so that the long term benefits of such upgrades could be realized by the Utility.

D. Section 1817 of the Energy Policy Act of 2005 requires the Department of Energy (DOE) to conduct a study in consultation with the Federal Energy Regulatory Commission (FERC) on the potential benefits of cogeneration and small power production. This study will encompass various forms of distributed energy technologies. The first component of this study is to analyze potential benefits associated with the expanded utilization of distributed generation technologies. APS proposes that the Commission defer any ruling on these types of benefits pending the outcome of the DOE study.

APS has not been able to identify DG projects that justify deferring transmission & distribution (T&D) investment. The net present value analysis of deferred T&D costs indicate there is not a significant incentive to defer T&D investment.

8. What are other issues related to net metering?

APS Response:

APS has identified the following additional issues related to net metering:

A. APS' Proposed Net Metering Rate Schedule:

The net metering program, as proposed within Rate Schedule EPR-5, is intended to attract small customers to install renewable generation by providing an additional incentive beyond the credit purchase program offered under the Company's Solar Partners Incentive Program.

APS is proposing a net metering rate schedule in Docket No. E-01345A-05-0816 (Rates for Renewable Resources EPR-5). This is a three year pilot program for renewable resource generation facilities, as defined in A.A.C. R14-2-1618 or successor, where the customer's generator(s) and load are located at the same premise. The proposed pilot schedule will be available to customers with a generator having a nameplate rating of 10 kW or less that are also served under a qualifying standard retail rate schedule. Qualifying standard retail rate schedules for service under this pilot program are limited to APS Rate Schedules E-12, ET-1, ET-2, ECT-1R and ECT-2 for residential customers and Rate Schedules E-32 and E-32TOU for general service customers with a monthly maximum demand of 20kW or less. The Company is proposing to limit participation in the program to 15 MW and to customers that own renewable resource generation facilities with a generator nameplate rating of 10 kW or less. In addition, this schedule permits excess energy returned to the APS grid to be carried from month to month with any excess supply reset to zero at the end of each calendar year. APS currently offers rate Schedule EPR-2, which is available to all Qualifying Facilities ("QF") cogeneration and small power production facilities up to 100 kW. EPR-2 is similar to the proposed EPR-5 net metering rate in a number of ways. For example, the EPR-2 customer operates a distributed generation system in parallel with the APS grid. The customer is allowed to generate all or part of their own energy needs with the backing of APS' system without paying for any standby charges. The customer is also compensated for any excess generation that flows back to the APS grid. The key difference between EPR-2 and the proposed EPR-5 net metering rate is that under EPR-2, the customer's excess generation energy is compensated at an avoided cost rate, while EPR-5 allows the excess energy to be netted on a kWh basis against energy purchased from APS over an annual period. The EPR-2 rate also has additional monthly service and incremental meter charges to pay for the increased service costs, which the Company is proposing to eliminate as discussed below, while EPR-5 does not have these additional monthly charges.

For larger commercial and industrial customers, the Company offers partial requirement Rate Schedules E-32R, E-52, and E-55 for those customers with parallel distributed generators larger than 100 kW.

B. Utility Un-recovered Fixed Cost to Serve Participants The Company has proposed recovery of utility un-recovered fixed costs to serve participants ("un-recovered costs") in Docket No. E-01345A-05-0816. The Company believes that it is appropriate to collect un-recovered costs from the Net Metering Pilot Program, which offers a special financial subsidy to participating customers in order to promote small renewable distributed generation systems. Un-recovered costs from the net metering program occur for two reasons. First, while the participating customer provides some of their own energy needs through their distributed generator, they are still connected to the grid and rely on APS to back up their distributed generator and provide their remaining energy needs.

Second, because the excess power that the customer generates above their own needs, which flows back to the grid, is compensated at an amount that is above the Company's avoided cost, the customer receives a credit equal to the entire energy charges in their applicable rate schedule, which includes generation, transmission, distribution, system benefits, DSM, PSA, regulatory assessment, CRCC, EPS and other energy-based charges. Therefore, because the Company incurs un-recovered fixed costs as a result of net metering, recovery of said costs is appropriate.

Un-recovered costs would be recovered through the EPS budget and reported to the Commission as part of the reporting requirements of the EPS program.

C. Distribution System Planning Using a detailed criterion, the distribution system planning process is used to identify capital improvements that are necessary to maintain high quality, reliable, and safe electric service to our customers. The purpose of this section is to identify concerns related to effects of substantial increases of distributed generation the effects on the current Distribution System Planning Process.

a) Facility Loading (transformers, wires, and, switches)

Separate computer model scenarios would need to be performed to analyze system performance. Typical models would include varying levels of distributed generation (DG) output with respect to light and heavy load conditions. APS will not control the scheduling or availability of DG unit but will still have the responsibility of supplying the customer's total load. For this reason, APS believes that DG owners should be required to pay for reserve capacity.

b) Voltage profiles (from the substation to the end-of-line)
Proper voltage profile planning is required for the multiple computer model scenarios needed to analyze system performance. With the addition of DG and the lack of control APS has in scheduling DG units, this process becomes much more complex. For example, voltage control and power factor correction may require additional more sophisticated voltage control equipment.

c) System protection (breakers, reclosers, sectionalizers, and fuses)
Additional and/or more sophisticated system protection equipment may be required depending on the size and location of the distributed generation unit.

d) Contingency planning (load transfers)
Load transfers, outage restoration and switching procedures become more complicated for operating personnel and may require additional time to accomplish due to distributed generation.

The current distribution system is a simple radial system. The addition of distributed generation to the current distribution system in effect creates a mini grid system. In comparison, a transmission system is an interconnected grid system and as such requires a significantly greater amount of computer analysis as compared to a radial system. Mini-grid systems require a more complex computer program and require that all contingencies (load transfers) be modeled. In other words, the installation of distributed generation increases the level of complexity of the distribution system significantly.

RESPECTFULLY submitted this 25th day of October, 2006.

SNELL & WILMER L.L.P.

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Original and 13 copies filed this
25th day of October, 2006, with:

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